An Optimized Petroleum Coke IGCC Coproduction Plant

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Phil Amick, Global Energy, Inc.
Robert Geosits, Bechtel Corporation
Ron Herbanek, Global Energy, Inc.
Sheldon Kramer, Nexant, Inc.
John Rockey, NETL
Samuel Tam, Nexant, Inc.

The *Vision 21* concept is the approach being developed by the U. S. Department of Energy (DOE) to promote energy production from fossil fuels in the 21st century. It will integrate advanced concepts for high efficiency power generation and pollution control into a new class of fuel-flexible facilities capable of coproducing electric power, process heat, high value fuels, and chemicals with virtually no emissions of air pollutants. It will be capable of a variety of configurations to meet different marketing needs, including both distributed and central power generation.

Vision 21 includes plans to give integrated gasification combined cycle (IGCC) systems a major role for the continued use of solid fossil fuels. Gasification systems are inherently clean, relatively efficient, and commercially available for converting inexpensive fuels such as coal and petroleum coke into electric power, steam, hydrogen, and chemicals. However, the gasification system also is relatively complex and costly to build and operate. The goal of this study is to improve the profitability of gasification projects by optimizing plant performance, capital cost, and operating costs. The key benefit of doing this methodical cost optimization process off-line is that it removes the schedule constraints associated with project development that tend to inhibit innovation and implementation of new ideas.

In late 1999, the National Energy Technology Laboratory awarded Nexant Inc. (a Bechtel Technology & Consulting Company) and Global Energy, Inc. (which acquired the gasification related assets of Dynegy Inc., of Houston, Texas including the E-Gas gasification technology, formerly the Destec Gasification Process) a contract to optimize IGCC plant performance.[1] Task 1 of this contract developed two optimized IGCC plant configurations: (1) petroleum coke gasification for electric power with the coproduction of hydrogen and industrial-grade steam, and (2) coal gasification for electric power generation only. Task 2 will optimize two different IGCC plant configurations: (1) petroleum coke gasification for electric power with the coproduction of liquid transportation fuels, and (2) coal gasification for electric power with the coproduction of liquid transportation fuels. Task 3 will develop conceptual designs and projected costs for advanced gasification plants including the integration with fuel cells and/or the addition of carbon dioxide control technologies.

This paper describes the optimization and cost reduction techniques used, presents the optimized designs, and summarizes plant performance for the petroleum coke IGCC coproduction plant. It also provides cost information and presents a financial analysis. Finally, based on recent Wabash River operating experience, the potential for further design enhancements, cost reductions, performance improvements, and market penetration is discussed.

[1] Contract No. DE-AC26-99FT40342, "Gasification Plant Cost and Performance Optimization"

The Wabash River Coal Gasification Repowering Project

In 1990, Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana formed the Wabash River Coal Gasification Repowering Project Joint Venture to participate in the Department of Energy's Clean Coal Technology Program by demonstrating the coal gasification repowering of an existing 1950's vintage generating unit. In September 1991, the project was selected by the DOE as a Clean Coal Round IV project to demonstrate the integration of the existing PSI steam turbine generator and auxiliaries, a new combustion turbine, a heat recovery steam generator, and a coal gasification facility to achieve improved efficiency and reduced emissions. In July 1992, a Cooperative Agreement was signed with the DOE.[2] Under terms of this agreement, the Wabash River Coal Gasification Repowering Project Joint Venture developed, constructed and operated the coal gasification combined cycle facility. The DOE provided cost-sharing funds for construction and a three-year demonstration period.

The participants jointly developed, separately designed, constructed, owned, and operated the integrated coal gasification combined-cycle power plant, using Destec's coal gasification technology to repower the oldest of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The gasification process integrates a new General Electric 7FA combustion turbine generator and a heat recovery steam generator (HRSG) to repower the 1950s-vintage Westinghouse steam turbine generator using some of the pre-existing coal handling facilities, interconnections, and other auxiliaries.

Commercial operation of the facility began late in 1995. Within a few months, both the gasification and combined-cycle plants successfully demonstrated the ability to run at capacity and within environmental compliance while using locally mined high sulfur Illinois Basin bituminous coal.[3] However, the first year of operation resulted in only a 35% annual availability, with over one half of the outage time being attributable to the dry char particulate removal system which experienced frequent failures of the ceramic candle filters. The facility has modified the particulate removal system including the use of metallic filters and has made significant improvements in other areas such as COS catalyst durability, chloride removal, and ash deposition control. As a result, step improvements in production were made during the second and third years of commercial operation. During the third year, operations were demonstrated on a second coal feedstock as well as a blend of two different Illinois No. 6 coals. This ability to blend coal feedstocks has improved the fuel flexibility for the site. Additionally, two successful tests using petroleum coke (including one from a refinery processing Mayan crude) were completed in November 1997 and September 1999 further demonstrating the fuel flexibility of the technology. At operational rates of about 2,000 TPD of petroleum coke, over 250 MW of power was generated from the gas turbine combined cycle power plant while meeting all emission criteria. The results of the petroleum coke tests have been previously described.[4]

The gasification facility also produces two commercial by-products. Sulfur is removed as 99.99 percent pure elemental sulfur and sold to sulfur users. Slag is being marketed for use as an aggregate in asphalt roads, as structural fill in various types of construction applications, as roofing granules, and as blasting grit.

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[2] Contract No. DE-FC21-92MC9310, "Wabash River Coal Gasification Repowering Project"

[3] Topical Report Number 7, "The Wabash River Coal Gasification Repowering Project," Contract No. DE-FC21-92MC9310, November, 1996, http://www.netl.doe.gov/publications/others/topicals/topical7.pdf.

[4] Phil Amick, *Commercial Operation of the Wabash River Gasification Project,* AIChE Spring National Meeting, Session T9011, New Orleans, March 9, 2000.

In 1998, the plant surpassed milestones of 10,000 hours of coal operation, 1,000,000 tons of coal processed, and achieved 77% availability for the third year of commercial operations (excluding downtime attributed to the combined cycle power generation section and for alternative fuel testing).[5] Since Spring 2000, the plant has been fueled by delayed petroleum coke and has been operating with minimal problems and significantly improved on-stream performance.

The repowering project demonstrated the ability to run at full load capability (262 MW) while meeting the environmental requirements for sulfur and NOx emissions. Cinergy, PSI's parent company, dispatches power from the Project with a demonstrated heat rate of 8,900 Btu/kWh (HHV), second only to their hydroelectric facilities on the basis of environmental emissions and efficiency.

Currently, the Wabash River Coal Gasification Repowering Project is the largest single train gasification facility in the Western Hemisphere, as well as the cleanest coal fired plant of any kind in the world. Global Energy now owns and operates the facility, and has renamed the Destec Gasification Process as the E-GAS™ Technology for future applications.

Based on the Wabash River Coal Gasification Repowering Project, Global Energy, Bechtel and Nexant are contributing their combined design, engineering, construction, and operating expertise to develop optimized designs for state-of-the-art IGCC plants processing either coal or petroleum coke.

The Wabash River Greenfield Project Plant

The gasification optimization work began with reviewing and assessing data from the existing Wabash River Project facility. Using the existing plant as the basis, design and cost engineers adjusted the plant's scope – equipment, materials, and process operation – so that the Wabash River project design was transformed into a greenfield IGCC design as shown in Step 1 of Figure 1. In Step 2, the coal plant was converted to a trigeneration facility using petroleum coke as fuel and producing electricity, hydrogen, and industrial-grade steam. The paths to optimize the coal and petroleum coke plants are Steps 3 and 4 in the figure.

Figure 2 is a simplified block flow diagram showing the major process blocks in the Wabash River Project Greenfield Plant developed in Step 1. Table 1 shows the coal properties and the major feed and product rates for the plant.

Capital cost is a key part of IGCC economics and profitability. The following three-stage cost estimating methodology was employed to develop a mid-year 2000 total installed cost for a greenfield plant equivalent to the Wabash River Coal Gasification Repowering Project, but located at a generic site in a typical Mid-Western state.

- **Derive a Cost Database from the Existing Wabash River Project Facility.** The initial cost database was set up using the documented equipment and construction material prices from the Wabash River Coal Gasification Repowering Project. The actual costs from the project were adjusted to eliminate the impact of unusual circumstances and escalated to today's values. The costs of any required equipment and materials that were not part of the new scope (such as the existing facilities; i. e., the repowered steam turbine), were added to the cost database.

[5] " Wabash River Coal Gasification Repowering Project, Final Technical Report", U. S. Department of Energy, Contract Agreement DE-FC21-92MC29310, http://www.lanl.gov/projects/cctc/resources/pdfs/wabsh/Final%20_Report.pdf, August 2000.

- **Evaluate Changes and Incorporate the Effects of Changes into the Capital and Operating Costs.** Modifications to major pieces of equipment required during the demonstration period were considered, and, if necessary, new cost quotes were obtained. One example of this is the previously mentioned change from ceramic candle filters to metallic ones. The Bechtel estimating tool, COMET, was used to benchmark the bulk material quantities and to provide a basis for evaluating future changes. This tool enabled the study team to alter the plant layout as a result of process improvements, equipment size changes, etc., and to determine the net effect on piping and other bulk material quantities.

- **Develop a Method for Adjusting Base Case Capital Costs to Estimate Other Design Configurations.** Evaluations of alternate plant configurations required a standard methodology for estimating the resulting capital costs. The format for this estimating tool was developed based on historical data, escalation indices and vendor quotes and will be employed on subsequent tasks in this study and for future project development activities.

The Non-optimized Petroleum Coke IGCC Coproduction Plant

The present-day market for solid feed gasification applications appears to be directed toward the use of low value fuels such as petroleum coke. In Step 2 the stand-alone coal-based Wabash River Greenfield Project Plant was reconfigured to use coke and produce power, steam, and hydrogen for an adjacent petroleum refinery and was moved to the Gulf Coast. Gasifier performance on petroleum coke is based on the current petroleum coke operations at the Wabash River facility.

The basis for the design of the non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant was that the steam and hydrogen products that it produces must have a high reliability and can be sold to the adjacent petroleum refinery. Because a single gasification train with backup natural gas firing can satisfy the refinery steam and hydrogen requirements by sacrificing electric power production, all critical parts of the plant were replicated to provide high reliability of a single gasification train. For example, the slurry preparation and slurry storage contain two duplicate 100% trains each with sufficient capacity for the entire plant. The entire gasification area from the slurry pumping and heating sections to the acid gas removal area, including the sulfur recovery facilities, and hydrogen production facilities consist of three duplicate trains each with a capacity of 50% of the total plant design capacity. Figure 3 is a simplified block flow diagram of the non-optimized plant showing the major processing areas and major process streams between processing areas. The processing functions in the balance of plant area, such as makeup water treatment, are not shown. Figure 4 is a train diagram of the plant showing the replication of the major plant sections.

Because this plant now becomes an integral part of the petroleum refinery by supplying high-purity hydrogen and steam to the petroleum processing units, it must be highly reliable since unexpected outages can have severe economic consequences to the refinery operations. This high degree of sparing (100% capacity when any one unit is down) and reliability is typical of today's petroleum coke IGCC coproduction plant market.

Thus, based on the greenfield plant of Step 1 and location adjustments, the plant was enlarged and re-engineered to process petroleum coke, rather than coal, to produce hydrogen and industrial-grade steam in addition to electric power from two base loaded GE 7FA combustion turbines.. This plant is located at a generic U. S. Gulf Coast site adjacent to a large petroleum refinery. The plant consumes 5,249 TPD of dry petroleum coke and produces 395.8 MW of export electric power, 79.4 MMscfd of hydrogen, 980,000 lb/hr of 700 psig/750^{o}F steam, and 367 TPD of sulfur. It also produces 99.6 MMscfd of a low Btu fuel gas (87 Btu/scf HHV) for sale to the adjacent petroleum refinery. Table 1 shows the coke properties and the major design and operating conditions for the non-optimized petroleum coke IGCC coproduction plant.

The Subtask 1.2 plant uses two GE 7FA gas turbines; the same gas turbine as used at the Wabash River facility. A current, more efficient steam turbine that was optimized for this application was used rather than the 1953 vintage steam turbine that was repowered at Wabash River. New petroleum coke receiving and storage facilities were designed to replace the coal facilities since the Wabash River Repowering Project used the existing facilities. New fresh water treatment facilities, a cooling water recirculation loop, and a cooling tower were added to replace the once through cooling water system. New waste water cleanup facilities also were designed to allow compliance with water discharge criteria and commingling of waster water with the refinery waste water outfall.

The mid-year 2000 installed cost of the non-optimized petroleum coke IGCC plant is 993.2 MM$. All installed plant costs cited in this paper are EPC costs which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs).[6] They also assume that process effluent discharges are permitted.

The Optimization Process

After Steps 1 and 2 were completed, the next step was to optimize the petroleum coke IGCC plant. Process and project optimization was guided by Bechtel's Value Improvement Practices (VIPs) methodology using the following VIPs:

- Technology Selection
- Process Simplification
- Classes of Plant Quality
- Process Reliability Modeling
- Design-to-Capacity
- Predictive Maintenance
- Traditional Value Engineering
- Constructability and Schedule Optimization

Initially, Bechtel and Global Energy prepared a Value Improvement Plan. This plan determined that the above practices were most applicable to this study. "Champions" were assigned to each applicable practice, and those champions along with the Value Improvement Plan administrator were responsible for implementation of the VIP process as well as documenting the results. Bechtel and Global Energy thoroughly analyzed the Value Engineering ideas generated during the brainstorming sessions to determine which were applicable for improving the project by assessing their benefits.

The VIP efforts were concentrated in the gasification area, specifically on the gasification and waste heat recovery section, the particulate removal section, the raw gas cooling area, and the syngas cleanup area. Lessons learned from plant operations showed that these areas are critical to reliable operations and high on-stream factors. In the Traditional Value Engineering VIP, almost 300 different ideas were generated in several brainstorming sessions. These ideas are based on (1) actual operations and maintenance experience at the Wabash River plant, (2) the construction of the Wabash River Repowering Project, and (3) Bechtel's

[6] These excluded items are included in the subsequent discounted cash flow financial analysis.

experience in other gasification and power generation projects with similar equipment. Operating personnel from the Wabash River facility proposed many of these ideas.

In conjunction with the Value Improvement Plan, Bechtel used the COMET plant layout program to evaluate and optimize equipment layout arrangements and minimize the piping requirements for a given area or between areas. By changing the location of any equipment item in a given area, COMET readjusts the interconnecting piping and recalculates new quantities. This optimization tool is especially beneficial in cases where a large percentage of the piping is large bore or high cost alloy material. Additionally, the COMET program also is capable of automatically generating plot plans and three-dimensional architectural renderings of the plant.

For several years now, Bechtel has been optimizing the heat integration of their standard coal and gas-based power plant designs. As a consequence, Bechtel has developed a *Powerline* suite of templates for combined cycle, pulverized coal, and fluidized bed power plant designs.[7] These *Powerline* plants incorporate the most advanced technologies and best practices from Bechtel's engineering portfolio. Designing plants using standard templates saves engineering and procurement costs resulting in higher quality plants that are less expensive and require less time for construction. The lessons learned during the development of the *Powerline* templates also were applied to optimize the designs for the various subtasks.

Bechtel has created a number of supplier alliances, not only for major equipment manufacture and fabrication, but also for bulk materials. In addition to reducing the price of equipment, these alliances also shorten the engineering and procurement cycle resulting in a shorter overall project schedule and reduced EPC costs. Shorter schedules and reduced EPC costs translate into faster payback and increased profitability. These ideas also were be applied to optimize the designs.

Table 2 lists some of the major design improvements and changes that resulted from the application of the above Value Improving Practices to the non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant design to generate the optimized Subtask 1.3 design.

The Optimized Petroleum Coke IGCC Plant Design

The base case design for the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant was developed based on the non-optimized design of the Subtask 1.2 plant. This plant also is located on the U. S. Gulf Coast adjacent to a petroleum refinery. In addition to the VIP items listed in Table 2, the following additional design changes were made for the optimized plant.

1. Newer GE 7FA+e combustion turbines with a higher capacity of 210 MW each and a higher thermal efficiency with lower NOx and CO emissions replaced the GE 7FA gas turbines.
2. The low Btu fuel gas is no longer exported to the refinery, but instead is used within the plant to make high pressure steam which is used to make additional electric power.
3. Redundant equipment was removed unless it was shown to be economically advantageous to retain the extra equipment for increased reliability.
4. The hydrogen plant was redesigned to be more efficient with improved heat recovery.
5. The number of gasification trains was reduced to 2 from 3, and a spare gasifier vessel was added to each train.

The major processing areas and major interconnecting streams for the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant are the same as those shown in Figure 3 for the non-optimized Subtask 1.2

[7] *Powerline* is a registered trademark of the Bechtel Corporation.

plant. Figure 5 is a train diagram of the optimized plant showing the replication of the major plant sections. Table 3 summarizes the Subtask 1.3 major plant input and output streams and compares them with those of the non-optimized plant. The optimized plant consumes 5,399 TPD of dry petroleum coke (about 3% more than the non-optimized plant) while using about the same size Air Separation Unit and produces 570 MW of gross power; 420 MW from the two combustion turbines and 150 MW from the steam turbine. It exports 461.5 MW of net electric power (about 17% more than the non-optimized plant) while producing the same amount of hydrogen and steam. The increased export power production is attributable to a more efficient design, to higher performance equipment, and to the internal use of the low Btu fuel gas to make additional high pressure steam.

Compared to the non-optimized plant design, the amount of redundant equipment has been significantly reduced.

- The slurry preparation area has been reduced to two 50% trains with two 60% rod mills compared to the non-optimized case which has two 100% trains.
- The gasification, HTHR (high temperature heat removal), and particulate removal (wet scrubbing) contains two 50% gasification trains each with a spare gasifier vessel compared to three complete 50% trains.
- The three 50% trains in the low temperature heat removal (LTHR), acid gas removal (AGR), and sour water treatment areas have been reduced to two 50% trains for the LTHR and AGR areas, and a single 100% sour water treatment area.
- The CO shift and PSA (hydrogen production area) contains two 50% trains compared to three in the non-optimized plant.
- The hydrogen compression area still contains three 50% hydrogen compressors because of their relatively high maintenance requirements.
- The three 50% trains in the sulfur recovery unit (SRU), hydrogenation, and tail gas recycle area have been reduced to two 50% trains for the optimized plant.
- Minor reductions of replicated and unnecessary equipment were made in other areas not mentioned above.

During the Value Improving Practices procedures, Process Availability Modeling studies suggested that a couple of alternate cases could be better than this base case depending upon the costs of replicating the gasification train and/or the gasification reactor vessels. Therefore, this case is designated as the base case, and two alternate cases were developed. These alternate cases will be discussed subsequently.

As a result of the Value Improving Practices effort, significant changes were made in the gasification area while developing the Subtask 1.3 optimized plant design from the Subtask 1.2 non-optimized plant design. In the Subtask 1.2 design, there are three identical and parallel gasification trains with each train having a single gasification reactor vessel. Only two trains will be operating at any one time with the third train acting as a spare. When maintenance work is required on an operating train, such as every other year when refractory replacement is required, it is shut down for repairs, and the spare train is placed on-line. When the repairs are completed, that train now becomes the spare train.

In the Subtask 1.3 optimized design, there are only two identical and parallel gasification trains, but each train contains a spare gasifier vessel that is not connected to the operating section. When it is necessary to replace the refractory in a gasifier, the train is shut down, and piping is rearranged to place the spare vessel in service and completely disconnect the previously operating vessel from the operating areas of the plant. The piping change-out time is expected to require about two weeks. Simultaneously, the normal outage maintenance is performed. When completed, the train is started up with the previously spare gasifier vessel in service. Since the gasifier requiring service now is completely isolated from the operating section, scheduled refractory replacement in the idle gasifier can be performed while the plant is operating at full capacity.

Because of various improvements incorporated the Subtask 1.3 design, less scheduled maintenance is required than at the Wabash River facility, and the scheduled outage periods can be shortened from twenty days to two weeks. Thus, the expected annual maintenance per train consists of only two two-week periods, or only four weeks per year.

Another change implemented in the optimization process was the use of full slurry quench in the gasifer second stage rather than using recycled syngas. This change improves the gasifier efficiency because it utilizes the heat in the syngas to promote the gasification reactions and saves the power needed to recycle the syngas.

Other significant design changes from the Subtask 1.2 design involve the syngas processing. In Subtask 1.2, the hot syngas leaving the gasifier goes to a hot residence vessel to allow further reaction. Following this, it is cooled in the high temperature heat recovery (HTHR) section, and dry char filters remove particulates. A wet scrubbing column downstream of the dry char filters removes chlorides. In Subtask 1.3, the post reactor residence vessel has been eliminated, and the hot syngas goes directly to the HTHR section. Most of the particulates (98+%) are removed from the syngas by a hot gas cyclone. The remaining particulates and chlorides, as well, are removed simultaneously by wet scrubbing with water. The particulates are concentrated and recovered from the wash water by a filter system before being recycled to the gasifier for further reaction. Filtered water is recycled to the wet scrubber or is sent to the sour water stripper.

Emissions performance of the non-optimized and Optimized Petroleum Coke IGCC Coproduction plants are similar as shown in Table 4. The reduced NOx and CO emissions of the optimized plant are the result of diluent injection and replacing the GE 7FA combustion turbine with the newer GE 7FA+e gas turbine which has both a higher power output and a higher thermal efficiency.

The mid-year 2000 installed cost of the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plan is 764.0 MM$, about 23% less than the non-optimized plant. Although both the Subtask 1.2 and Subtask 1.3 plant costs are mid-year 2000 costs, the Subtask 1.3 costs are more reflective of current market pricing. For the Subtask 1.3 plant, current vendor quotes were obtained for most of the added and high cost equipment. Power block costs are based on the actual costs of a similar power project, reflecting current market conditions. Because of the current demand for combustion turbines, the cost of the two turbines appears high compared to historical data.

If the three-train Subtask 1.2 plant were to be built using the Subtask 1.3 optimized gasification train design, that plant would cost about 880 MM$. This is a savings of 113 MM$ or just over 11%, essentially all of which is in the gasification and balance of plant areas.

Subtask 1.3 Minimum Cost Plant

To further reduce the cost of the Optimized Petroleum Coke IGCC Coproduction Plant a minimum cost plant design was developed. Figure 6 is a train diagram showing the replication of various plant sections in the Subtask 1.3 Minimum Cost Plant. In this design, the spare gasifier vessel was removed from each of the two parallel gasification trains resulting in only one gasifier per train; the same number as in

Subtask 1.2. As is the case with the Subtask 1.2 plant, each train will require a twelve week outage every other year for refractory replacement.

Because the only change between this case and the Subtask 1.3 Base Case (described in the previous section) is the elimination of the spare gasifier, the input and output stream flow rates and emissions performance will be the same as that for the Subtask 1.3 Base Case. However, because of lower availability, the annual power sales, the annual hydrogen, steam, and sulfur productions rates, and the annual coke consumption will be lower.

The Subtask 1.3 Minimum Cost Plant costs 746 MM$. The cost for all plant sections are the same as the Subtask 1.3 Base Case except for the gasification area which is 18 MM$ less. This difference represents the total installed cost of the two spare gasifiers, one in each train. Thus, the minimum cost case is 18 MM$ less than the optimized Optimized Petroleum Coke IGCC Coproduction Plant base case.

Subtask 1.3 Spare Gasification Train Plant Description

To increase the availability of the Optimized Petroleum Coke IGCC Coproduction Plant, a plant design was developed in which there is a spare gasification train containing all the equipment from the slurry feed preparation through the particulate removal areas. Each train has only one gasifier vessel as is the situation in Subtask 1.2 and in the Subtask 1.3 Minimum Cost case. Figure 7 is a train diagram showing the replication of various plant sections in the Subtask 1.3 Spare Gasification Train Plant. In this design, there are three identical and parallel trains containing the slurry feed tanks and pumps, gasifier, high temperature heat recovery unit (HTRU), and the dry/wet particulate removal system. Each train has a design capacity of 50% of the total plant capacity. This is the same gasifier design that is used in Subtask 1.2. Whenever one train has to be shut down for maintenance, the spare train will be placed in service. Once that train is repaired, it becomes the standby spare train until needed. Therefore, the expected annual maintenance requirements for the gasification area are about the same as the Subtask 1.2 plant. There is insufficient downstream processing capacity to allow for the simultaneous operation of all three gasification trains.

The only change between this case and the Minimum Cost Case (described in the previous sections) is the addition of the spare gasification train. Thus, the input and output stream flow rates and emissions performance of this option will be the same as those of the Subtask 1.3 Base Case. However, because of the higher availability, the annual power sales, annual hydrogen, steam and sulfur productions, and annual coke consumption will be higher.

The cost of the Subtask 1.3 Spare Gasification Train Plant is 812.6 MM$. The cost for all plant sections are the same as the Subtask 1.3 Base Case except for the gasification area which costs 48.5 MM$ more. This difference represents the net difference in total installed cost of the spare gasification train and the removal of the two spare gasifiers from the Base Case design. Thus, the Spare Gasification train case costs 48.5 MM$ more than the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant Base Case. The Spare Gasification train case costs 66.5 MM$ more than the Minimum Cost case

Use of Backup Natural Gas

The gasification trains of the Subtask 1.2 plant and all three Subtask 1.3 plants are sized so that one train has sufficient capacity to provide the design amounts of hydrogen and steam to the adjacent petroleum refinery. However, when only one gasification train is operating, there is insufficient syngas available to meet the hydrogen demand and fully fire one combustion turbine. Thus, in this situation, about 63.8 MMscfd of backup natural gas will be used to supplement the syngas and co-fire both combustion turbines. When this situation occurs, the power output from the combustion turbines is reduced. However, the internal power consumption within the plant also is reduced by the amount of power consumed by the idle gasification train and air separation unit. The net effect of this combination of events is that there is a net reduction in the export power.

In the less frequent situation where only one syngas train is operating and only one combustion turbine is available, backup natural gas also will be used to load the available gas turbine and supply the design hydrogen and steam demands. In this situation, the export power produced by the plant is slightly less than half the design rate.

In the least likely situation where both gasification trains are not available and only one combustion turbine is available, natural gas will be used to fire that turbine to produce only export power. No export steam or hydrogen will be produced.

Availability Analysis

In Table 5.0A of the Final Report for the Wabash River Wabash River Repowering Project, Global Energy reported downtime and an availability analysis of each plant system for the final year of the Demonstration Period.[5] During this March 1, 1998 through February 28, 1999 period, the plant was operating on coal for 62.37% of the time. There were three scheduled outages for 11.67% of the time (three periods totaling 42 days), and non-scheduled outages accounted for the remaining 25.96% of the time (95 days).

After adjustments, this data was used to estimate the availability of the Subtask 1.2 and Subtask 1.3 Petroleum Coke IGCC Coproduction Plant designs. Using the EPRI recommended procedure, availability estimates were calculated for the Subtask 1.2 non-optimized Petroleum Coke IGCC Coproduction Plant and for the three Subtask 1.3 optimized plant designs.[8]

Table 5 compares the design (stream day) and average daily (calendar day) feed and product rates for the non-optimized Subtask 1.2 case and the three Subtask 1.3 cases. As the table shows there are significant differences between the calendar day rates and the stream day rates for the power, sulfur, slag, and fuel gas products, and for the coke and flux feeds. This is because these design rates are based on two trains running simultaneously. The calendar day rates are closest to the design rates for the two cases with three gasification trains because only two of them need to be running simultaneously to make the design rates. For all cases, the calendar day steam and hydrogen rates are a lot closer to the design rates since only one gasification train has to be operating for the plant to produce the design product rates.

The daily average natural gas consumptions shown in Table 5 are the lowest for the two cases with three parallel gasification trains. This is because these cases have the highest availability of two trains. Thus, they, require the least amount of backup natural gas firing. The availability of the gasification trains in the Subtask 1.3 Base Case is higher than in the Subtask 1.3 Minimum Cost case because the former has a spare gasification reactor in each train. Consequently, the Base Case requires less natural gas usage than the Minimum Cost case.

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[8] Research Report AP-4216, *Availability Analysis Handbook for Coal Gasification and Combustion Turbine-based Power Systems*, Research Project 1800-1, Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA, 94304, August 1985.

Figure 8 compares the design and daily average coke consumptions for the plants. In all cases, the average daily coke consumption is significantly less than the design capacity. This difference is the least for the Subtask 1.3 Spare Gasification Train Case where it is only 585 TPD of dry coke less than the design capacity of 5,399 TPD, and it is the greatest for the Subtask 1.3 Minimum Cost Case where it is 1,426 TPD less. For the Subtask 1.3 Base Case, the average daily dry coke consumption is 1,090 TPD less than the design rate of 5,399 TPD.

Figure 9 shows the amount of time that the various plant sections are operating. For Subtask 1.2,

- two gasification trains and two combustion turbines (code: 2Gs & 2 CTs) are operating about 77.4% of the time;
- only 1 gasification train and 2 combustion turbines (code: 1 G & 2 CTs) are operating about 13.4% of the time;
- only 1 gasification train and 1 combustion turbine (code: 1 G & 1 CT) are operating about 8.4% of the time; and
- only 1 combustion turbine (Code: 0Gs & 1CT) are operating about 0.6% of the time.

Thus, for the Subtask 1.2 plant, one or more gas turbines are using natural gas as a backup fuel for about 22.4% of the time because an insufficient amount of syngas is available. The equivalent syngas availability is 88.3%, and the equivalent hydrogen and steam availability is 99.2%.

For the Subtask 1.3 Base Case, backup gas firing is used almost 38% of the time. The equivalent syngas availability is 79.8%, the equivalent hydrogen availability is 96.8 and the equivalent steam availability is 97.8%.

For the Subtask 1.3 Minimum Cost case, backup gas firing is used about 49.2% of the time. The equivalent syngas availability is 73.6%, the equivalent hydrogen availability is 96.6% and the equivalent steam availability is 95.6%.

The Subtask 1.3 Spare Gasification Train case uses backup natural gas firing for about 20.9% of the time because the individual gasification trains have the highest availability. The equivalent syngas availability is 89.2%, the equivalent hydrogen availability is 98.4%, and the equivalent steam availability is 99.4%.

Although not discernable in the figure, all four bars have the same height of 99.8%, which is the availability of one of the two combustion turbines.

Figure 10 shows the equivalent power availability using backup natural gas as a function of the design rate produced by each mode of operation for the four cases. The height of each bar represents the annual equivalent power availability of each case. The Subtask 1.3 Spare Gasification Train Case has the highest total equivalent power availability of 94.7%, and the Subtask 1.3 Minimum Cost Case has the lowest equivalent power availability of 92.4%. For the Subtask 1.3 Base Case, about 31.5% of the design power is made when some natural gas is being used either to supplement or replace the syngas, and for the Subtask 1.3 Spare Gasification Train Case, only about 15.8% of the power is being made when some natural gas is being used.

Discounted Cash Flow Financial Analysis

The financial analysis was performed using a discounted cash flow (DCF) model that was developed by Nexant Inc. (formerly Bechtel Technology and Consulting) for the DOE as part of the Integrated

Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices Task.[9] This model calculates investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of IGCC projects. The IGCC financial model consists of 18 coupled spreadsheets in a Microsoft Excel workbook format. The model spreadsheets are organized into four main sections; (1) data input sheets, (2) supporting analysis sheets, (3) financial statements, and (4) project summary results sheets.

Table 6 shows the required power selling price that will produce an after-tax return on investment (ROI) of 12%. (The other basic economic parameters are shown in the middle column of Table 7.) The Subtask 1.3 Spare Gasification Train Case has the lowest required selling price of 32.48 $/MW-hr (or 3.248 cents/kW-hr). The Subtask 1.3 Base Case has the next lowest required power selling price of 34.45 $/MW-hr followed by the Subtask 1.3 Minimum Cost case that has a required power selling price of 36.49 $/MW-hr. These three cases are a significant improvement over the Subtask 1.2 case which has a required power selling price of 43.36 $/MW-hr to produce a 12% after-tax ROI. Thus, the Subtask 1.3 Spare Gasification Train Case lowered the required power selling price by almost 11 $/MW-hr (or 1.1 cents/kW-hr), a 25% reduction.

Based on these results, the Subtask 1.3 Spare Gasification Train Case is the preferred Subtask 1.3 case because it has the highest return on investment and lowest required power selling price for a 12% after tax ROI even though it has the highest EPC cost.

Table 7 shows the sensitivity of some individual component prices and financial parameters for the Subtask 1.3 Base Case starting from a 12% ROI (with a power price of 34.45 $/MW-hr). Each item was varied individually without affecting any other item. The sensitivities of the other Subtask 1.3 cases will be similar. Most sensitivities are based on a ±10% change from the base value except when a larger change is used because it either makes more sense or it is needed to show a meaningful result. The power selling price is the most significant product price with a 10% increase resulting in a 3.27% increase in the ROI, and a 10% decrease resulting in a 3.40% decrease in the ROI. Hydrogen was the second most significant product price with a +10% increase resulting in a 1.07% increase in the ROI, and a 10% decrease resulting in a 1.08% decrease in the ROI. Steam was the next most significant with a +10% change resulting in a +0.69% increase in the ROI, and a –10% change resulting in a 0.70% decrease in the ROI. Changes in the sulfur and slag prices have only a small influence on the ROI.

A change in the coke price of 5 $/ton from the base coke price of 0 will change the ROI by +1.78% with an increase in the coke price decreasing the ROI and vice-versa. A change in the natural gas price of +10% (or +0.26 $/MMBtu) will change the ROI by +0.60% with an increase in the gas price causing a decrease in the ROI and vice-versa. The ROI essentially is insensitive to the flux price with a 100% change from the base price of 5 $/ton only causing the ROI to change by 0.04%.

The interest rate is the most sensitive of the financial parameters that were studied. A 20% decrease in the loan interest rate to 8% from the base interest rate of 10% will increase the ROI to 15.75% from 12.00%, and a 20% increase in the interest rate to 12% will lower the ROI to 8.20%. A 20% decrease in the loan amount from 80% to 72% will lower the ROI by 0.57% to 11.43%, and a 20% increase in the loan amount to 88% will increase the ROI by 0.96 to 12.96%. Decreasing the income tax rate by 10% from 40% to 36% will increase the ROI to 12.48%, and a 10% increase in the tax rate to 44% will lower the ROI by 0.52% to 11.48%.

[9] Nexant Inc., "Financial Model Users Guide – IGCC Economic and Capital Budgeting Evaluation", Report for the U. S. Department of Energy, Contract No. DE-AM01-98FE64778, May 2000.

Figure 11 shows the effect of only the power selling price on the after-tax ROI. As expected, the ROI is a strong function of the power price. The Subtask 1.3 ROIs are significantly better than those for Subtask 1.2 reflecting the effects of both the lower costs and higher gasification train availabilities of the Subtask 1.3 cases. The larger slopes of the Subtask 1.3 ROIs are a result of the lower capital costs of the Subtask 1.3 cases compared to the Subtask 1.2 case. As seen from the figure, the Subtask 1.3 Spare Gasification Train Case must have a required electric power selling price of about 35.8 $/MW-hr for a 15% after-tax ROI.

The solid points in Figure 11 are based on an 80% loan at a 10% interest rate and a 3% financing fee. The open points are based on a 8% loan interest rate and the same 3% financing fee. Reducing the loan interest rate increases the after-tax ROI by about 3.7%. At a 30 $/MW-hr power price, the ROI for the preferred Subtask 1.3 Spare Gasification Train Case increases to about 13.4%, and that for the Base Case increases to 11.3%.

Figure 12 shows the combined effect of changes in the natural gas price, steam, hydrogen, low Btu fuel gas, and power prices on the ROI for the four cases as a function of the product price index. Table 8 shows the relationship between product price index and the five commodity prices.

With a 10% increase in the product price index, the natural gas price increases to 2.86 $/MMBtu, and the Subtask 1.3 Spare Gasification Train Case has an ROI of about 12.1%. At a gas price of 3.13 $/MMBtu corresponding to a 1.2 product price index, the Spare Gasification Train Case has an ROI of about 16.6%. At the 1.2 price index, the Subtask 1.3 Base Case has an ROI of 14.5%.

The above economic analysis suggests that for situations where export power can be sold at attractive prices during the entire year, the Spare Gasification Train Case is the preferred case, since this case has the highest ROI. Although the most expensive case, on an annual basis, this case consumes the largest amount of coke per dollar of plant cost. It also is the most attractive case when coke storage facilities are limited and an alternate disposal means may be unattractive. This case also is the most attractive when outages in the steam and hydrogen supply will incur large penalties. In such a situation, additional redundancy in the hydrogen production facilities may be justified.

The Minimum Cost Case may be the most attractive in the situation where power prices are low in the spring and fall and long outages can be tolerated. This case has the lowest ROI. Although the least expensive case, on an annual basis, this case consumes the least amount of coke per dollar of plant cost. This case may be the most attractive when coke storage or alternate coke disposal means are available during outages. In the situation where a refinery expansion which will increase coke production is anticipated, the Minimum Cost Case may be preferred because it can be later expanded to either the Base Case or the Spare Gasification Train Case.

The Base Case may be the most attractive case when power prices are low in the spring and fall, but still reasonably attractive, and scheduled outages can be taken at these times. This case also may be the preferred case when the penalties associated with outages in the refinery steam and hydrogen supplies are not very large or alternate, but more expensive sources, are available.

Current Market Pricing

Currently, the United States is in a period of low inflation, and as a result, interest rates are low. Table 9 shows the effect of reducing the loan interest rate from 10% to a current market value of 8% while still maintaining the same 3% upfront financing charge. The first line shows the required power selling prices for a 12% ROI. Compared to the previous results shown in Table 6, the required power prices for the Subtask 1.3 cases have dropped by 2.7 - 5.8 $/MW-hr. The Subtask 1.3 Spare Gasification Train Case now requires a power selling price of 28.56 $/MW-hr for a 12% ROI. This price is very competitive when compared to the minimum price for cogeneration power in Texas.

Presently, there are wide variations in the future projections of the natural gas price. At the present time, a 3.00 $/MMBtu price for natural gas seems to be a reasonable value for economic projections. The bottom line shows the ROI when all the product prices are indexed to a 3.00 $/MMBtu natural gas price. This corresponds to a power price to 31.15 $/MW-hr. In this scenario, the ROIs have increased by another 3 to 4%. The Subtask 1.3 Spare Gasification Train Case now has an ROI of 18.15%. Based on these prices, an optimized coke fueled IGCC plant, such as that developed in this study, is poised to enter the power market.

Additionally, based on extensive review of the Wabash River operating experience over the past two years with the dry char particulate filters and additional analysis of a cyclone plus dry filter system, Global Energy is confident that the both the cost and reliability of the a dry particulate removal system can be significantly reduced. This advanced system would replace the cyclone / wet scrubbing system used in this study. Recent operating experience on petroleum coke indicates that this dry filter system will have near 100% availability without any increase in scheduled outage. For the preferred Spare Gasification Train Case, employing this advanced dry particulate removal system can increase the plant ROI by an additional 1.5%, thereby making dry particulate removal the preferred system for the next plant.

Summary

Global Energy’s process engineering, plant design and operation experience coupled with Bechtel’s design template approach and Value Improving Practices (VIP) procedures were employed to develop three optimized designs for petroleum coke IGCC coproduction plants. The most attractive of these designs is the one that contains a spare gasification train, and under a current day economic scenario, it appears economically viable.

Based on an optimized design for a future plant currently under development in Subtask 1.4, there are several opportunities for further cost reductions, such as:

- ◊ Economy of scale from increased combustion turbine capacity (and efficiency) from the use of a “H class” design
- ◊ Simplified gasification reactor design at higher pressure
- ◊ Implementation of slurry feed vaporization for increased efficiency
- ◊ Simplified heat recovery
- ◊ Simplified water treatment and zero liquid discharge of process water
- ◊ Further particulate filter advancements (such as metal to ceramics)
- ◊ Warm gas cleanup

The above enhancements are possible in the near future and will clearly benefit both coke and coal fueled IGCC technology thereby making coal based IGCC plants a clear leader in clean coal power technology.

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Table 1
Plant Design and Operating Conditions

	Subtask 1.1 Wabash River Greenfield Project Plant		Subtask 1.2 Petroleum Coke IGCC Coproduction Plant	
Location	Typical Mid-Western State		U.S. Gulf Coast near a Petroleum Refinery	
Feedstock	Illinois No. 6 Coal		Green Delayed Petroleum Coke	
	Dry Basis	As Rec'd	Dry Basis	As Rec'd
HHV, Btu/lb	12,749	10,900	14,848	13,810
Analysis, wt %				
Carbon	69.9	59.76	88.76	82.55
Hydrogen	5.0	4.28	3.20	2.98
Nitrogen	1.3	1.11	0.90	0.84
Sulfur	2.58	2.21	7.00	6.51
Oxygen	8.27	7.07	-	-
Chlorine	0.13	0.11	50 ppm	47 ppm
V & Ni	-	-	1900 ppm	1767 ppm
Ash	12.7	10.86	0.14	0.13
Moisture	-	14.5	-	6.99
Total	100	100	100	100
Inputs				
Fuel, dry basis	2,260 tons/day		5,250 tons/day	
Makeup Water,	2,280 gpm		4,830 gpm	
Refinery Condensate	0		686,000 lb/hr	
Outputs				
Export Power, MW	269.3		396	
Slag, tons/day	356		190	
Sulfur, tons/day	57		367	
Hydrogen	0		79.4 MMscfd	
Purity	-		99 %	
Pressure	-		1000 psig	
Temperature	-		120^oF	
Steam	0		980,000 lb/hr	
Pressure	-		700 psig	
Temperature	-		750^oF	
Waste Water	120 gpm		30 gpm	
Gas Emissions				
Particulates	Nil		Nil	
SOx, as SO_2	96.8% Removal		99.5 % Removal	
	312 lb/hr		306 lb/hr	
	42 ppmvd		20 ppmvd	
NOx, as NO_2	161 lb/hr		325 lb/hr	
	30 ppmvd		30 ppmvd	
CO	56 lb/hr		111 lb/hr	
	17 ppmvd		17 ppmvd	

Table 2

Subtask 1.3 Major VIP and Optimization Items

Plant **Section**	Description
100	Simplified the solids handling system
150	Removed the slurry feed heaters and spare pumps
300	• Maximized the use of slurry quench in the gasifier second stage • Maximized syngas moisturization • Used a cyclone and wet particulate removal system rather than dry char filters to clean the syngas • Improved the burner design • Removed the post reactor residence vessel
400/420	Simplified the Claus plant, amine, and sour water stripper resulting in lower incinerator emissions
500	• Used a state-of-the-art GE 7FA+e gas turbine with 210 MW output and lower NOx • Combined syngas moisturization with use of the least cost diluent (steam) in the gas turbine
General	• Bechtel's Powerline cost and philosophy applied to an IGCC plant; i.e., a building block approach • Bechtel's MPAG (Multi Project Acquisition Group) was used to obtain low equipment and bulk material costs • Availability analysis was used to select design with maximum on-stream time • The COMET plant layout model was used to develop a compact plant layout and minimize amount of high cost and alloy piping. • Design features were added to reduce the O&M costs

Table 3
Design Input and Output Streams for the Optimized and Non-optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Plant
Plant Input		
Coke Feed, as received, TPD	5,515	5,673
Dry Coke Feed to Gasifiers, TPD	5,249	5,399
Oxygen Production, TPD of 95% O_2	5,962	5,917
Total Fresh Water Consumption, gpm	4,830	5,150
Condensate Return from the Refinery, lb/hr	686,000	686,000
Flux, TPD	107	110.2
Plant Output		
Net Power Output, MW	395.8	461.5
Sulfur, TPD	367	371.8
Slag, TPD (15% moisture)	190	194.5
Hydrogen, MMscfd	79.4	80
HP Steam, 700 psig/750^{o}F, lb/hr	980,000	980,000
Fuel Gas Export, MMscfd	99.6	0
MMBtu/hr, (HHV)	363	0

Table 4
Total Emissions Summary for the Optimized and Non-optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Plant
Total Exhaust Gas Flow Rate, lb/hr (see note)	7,588,700	8,602,300
Emissions		
SOx ppmvd	20	24
SOx as SO_2, lb/hr	306	385
NOx, ppmvd	30	14
NOx as NO_2, lb/hr	325	166
CO, ppmvd	17	15
CO, lb/hr	111	105
CO_2, lb/hr (see note)	1,019,074	1,438,367
VOC and Particulates, lb/hr	NIL	NIL
Opacity	0	0
Sulfur Removal, %	99.5	99.4

Note: The exhaust gas flow rate and CO_2 rate for the Subtask 1.3 optimized plant include burning the low Btu PSA off gas to make high pressure steam, but for the non-optimized Subtask 1.2 plant, the low Btu PSA off gas is sold as fuel gas to the refinery.

Table 5
Design and Daily Average Feed and Product Rates for Subtasks 1.2 and 1.3

	Subtask 1.2		**Subtask 1.3**			
				Daily Average		
Case	Design	Daily Average	Design	Base Case	Minimum Cost Case	Spare Solids
Product Rates						
Power, MW	395.8	374.3	460.7	430.0	425.4	436.4
Steam, Mlb/hr	980.0	972.2	980.0	958.6	946.2	974.1
Hydrogen, MMscfd	79.4	78.8	80.0	77.5	76.5	78.7
Sulfur, TPD	367.0	324.1	371.8	296.8	273.6	331.5
Slag, TPD	190.0	167.8	194.5	155.3	143.1	173.4
Fuel Gas, MMscfd	99.6	98.8	0	0	0	0
Input Rates						
Coke, TPD	5,249	4,635	5,399	4,310	3,973	4,814
Flux, TPD	107	94.5	110.2	88.0	81.1	98.3
Natural Gas, MMBtu/d	0	10,099	0	20,000	26,977	9,303

Table 6
Basic Financial Model Results

	Subtask 1.2	Subtask 1.3 Base Case	Subtask 1.3 Minimum Cost Case	Subtask 1.3 Spare Gasification Train Case
Required Power Selling Price for a 12% after-tax ROI, $/MW-hr	43.36	34.45	36.49	32.48

Table 7
Sensitivity of Individual Component Prices and Financial Parameters on the Subtask 1.3 Base case Starting from a 12% ROI (with a Power Price of 34.45 $/MW-hr)

	Decrease			Base	Increase		
	ROI	Value	% Change	**Value**	% Change	Value	ROI
Products							
Power	8.60%	31.00 $/MW-hr	-10%	**34.45 $/MW-hr**	+10%	37.90 $/MW-hr	15.27%
Hydrogen	10.92%	1.17 $/Mscf	-10%	**1.30 $/Mscf**	+10%	1.43 $/Mscf	13.07%
Steam	11.30%	5.04 $/t	-10%	**5.60 $/t**	+10%	6.16 $/t	12.69%
Sulfur	11.93%	27 $/t	-10%	**30 $/t**	+10%	33 $/t	12.07%
Slag	11.94%	-5 $/t	---	**0 $/t**	---	5 $/t	12.06%
Feeds							
Coke	13.75%	-5 $/t	---	**0 $/t**	---	5 $/t	10.25%
Natural Gas	12.60%	2.34 $/MMBtu	-10%	**2.60 $/MMBtu**	+10%	2.86 $/MMBtu	11.39%
Flux	12.04%	0 $/t	100%	**5 $/t**	+100%	10 $/t	11.96%
Financial							
Interest Rate	15.75%	8%	-20%	**10%**	+20%	12%	8.20%
Loan Amount	11.43%	72%	-20%	**80%**	+20%	88%	12.96%
Tax Rate	12.48%	36%	10%	**40%**	+10%	44%	11.48%

Note: Products and Feeds each are listed in decreasing sensitivity.

Table 8
Product Price Index and Commodity Prices

Product Price Index	Natural Gas, $/MMBtu	Power, $/MW	Hydrogen, $/Mscf	Steam, $/ton	Fuel Gas, $/Mscf
1.00	2.60	27.00	1.30	5.60	0.2274
1.05	2.73	28.35	1.43	5.88	0.2388
1.10	2.86	29.70	1.58	6.16	0.2501
1.15	2.99	31.05	1.69	6.44	0.2615
1.20	3.12	32.40	1.82	6.72	0.2729

Table 9
Financial Model Results with an 8% Loan Interest Rate

	Subtask 1.2	Subtask 1.3 Base Case	Subtask 1.3 Minimum Cost Case	Subtask 1.3 Spare Gasification Train Case
Required power selling price for a 12% return on investment	37.52	31.68	32.79	28.56
Return on investment with all prices indexed to 3.00 $/MM Btu Natural Gas	11.55%	15.99%	13.65%	18.15%

Figure 1

Steps for Optimization of the Coal IGCC Design and the Petroleum Coke-IGCC Coproduction Plant

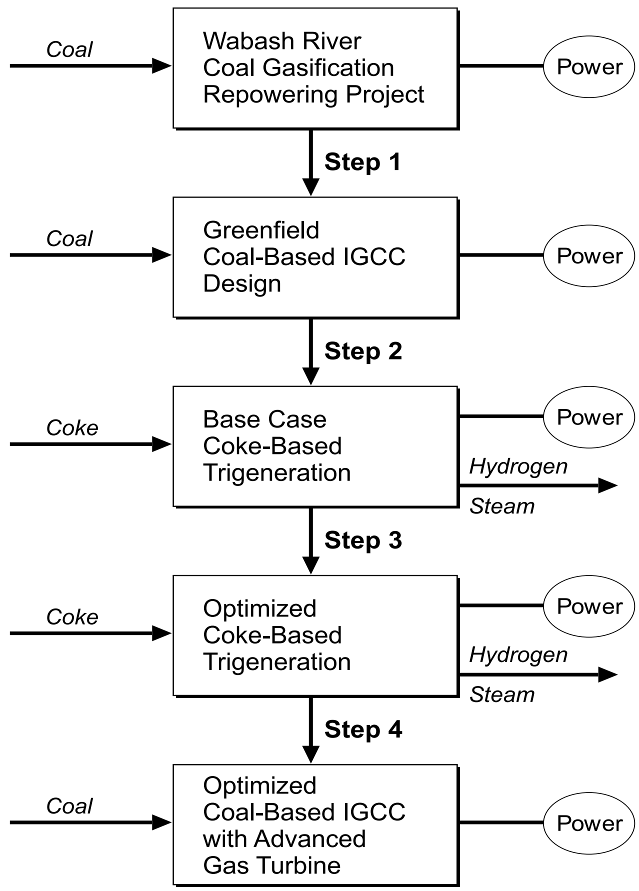

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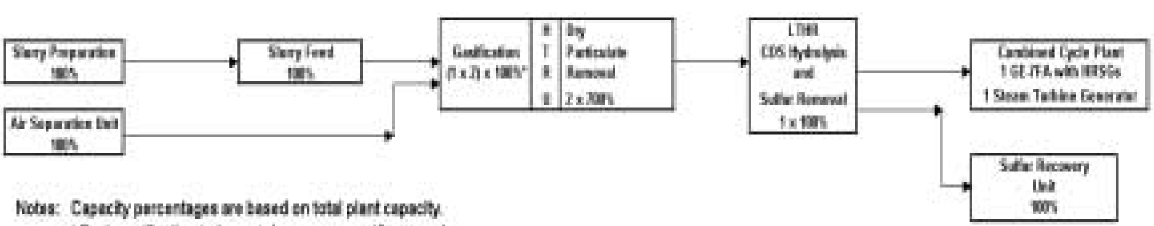
Figure 2

Wabash River Greenfield Plant

Block Flow (Train) Diagram



Notes: Capacity percentages are based on total plant capacity.
* Each gasification train contains a spare gasifier vessel.

Figure 3

Petroleum Coke IGCC Coproduction Plant
Simplified Block Flow Diagram

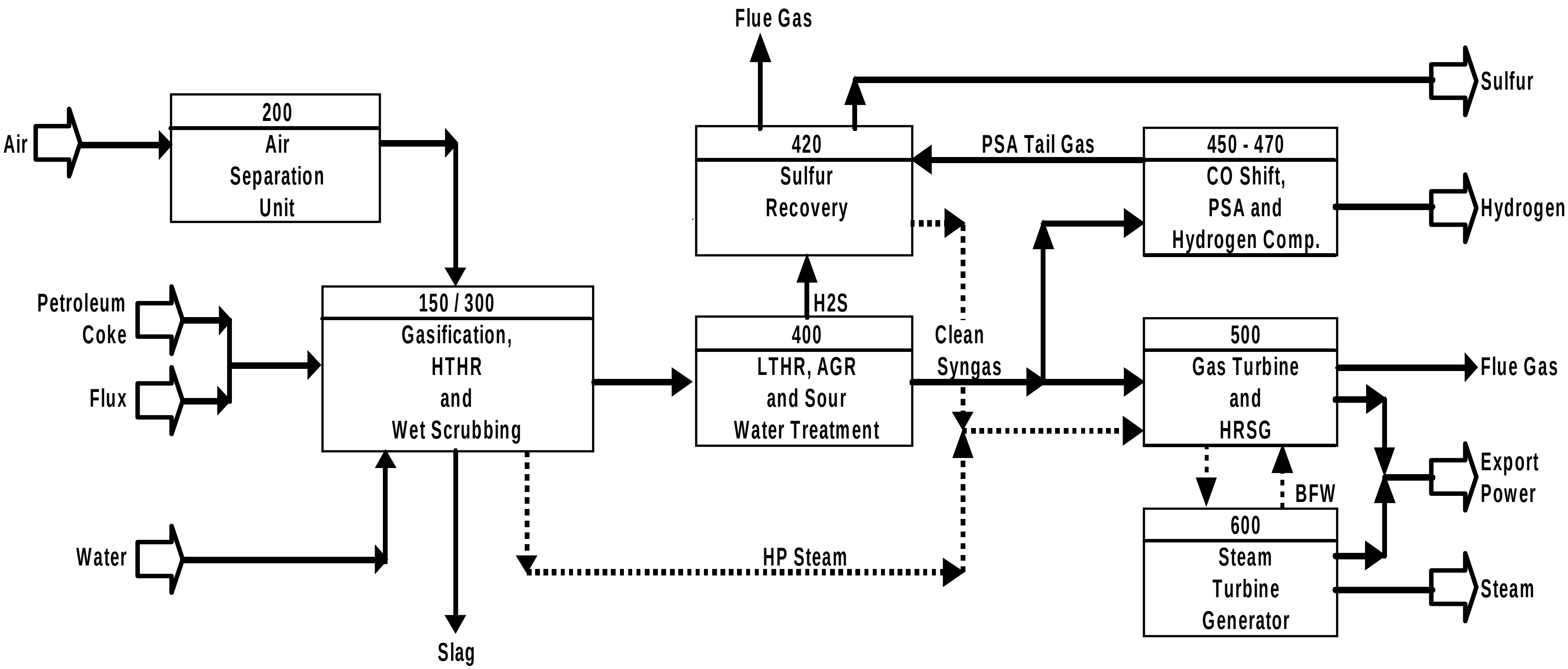
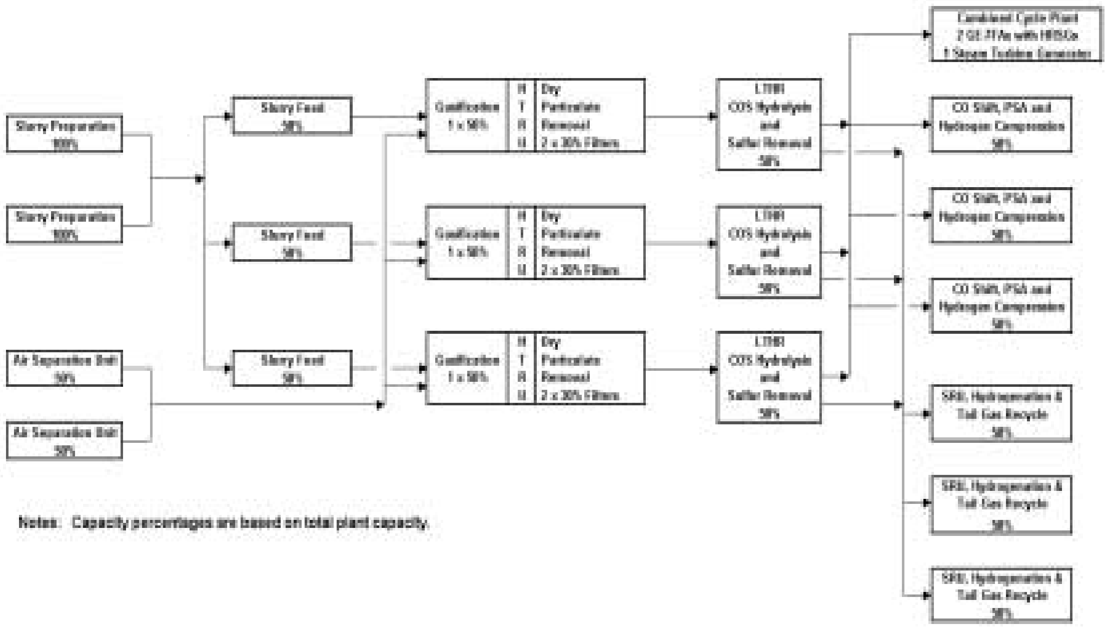


Figure 4

Subtask 1.2 - Block Flow (Train) Diagram

Non-optimized Petroleum Coke IGCC Coproduction Plant

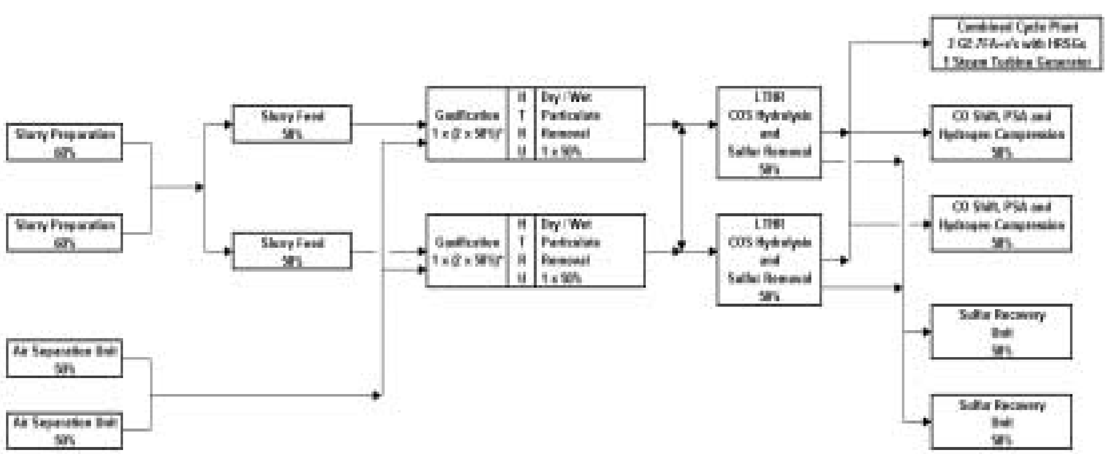


Notes: Capacity percentages are based on total plant capacity.

Figure 5

Subtask 1.3 Base Case - Block Flow (Train) Diagram

Optimized Petroleum Coke IGCC Coproduction Plant

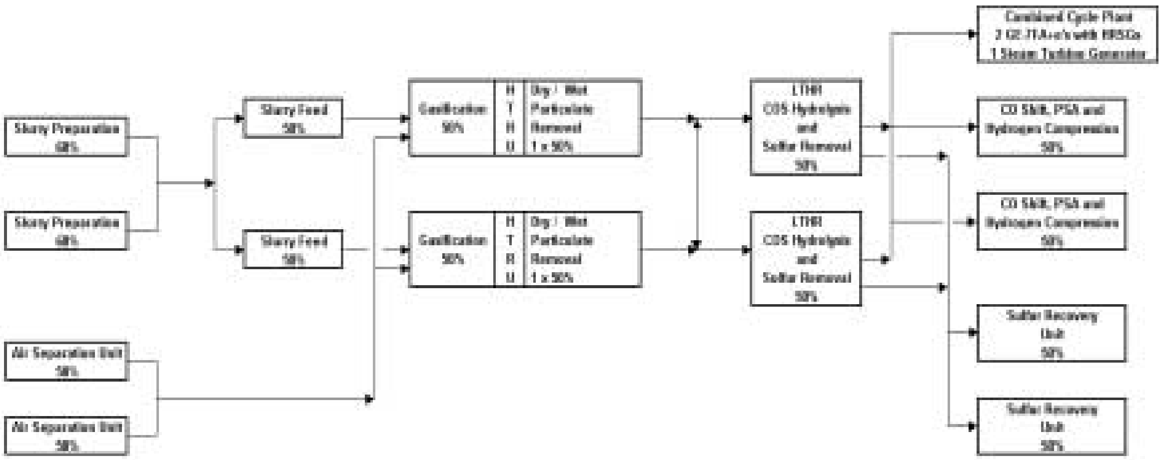


Notes: Capacity percentages are based on total plant capacity.
* Each gasification train contains a spare gasifier vessel.

Figure 6

Subtask 1.3A Minimum Cost Case - Block Flow (Train) Diagram

Optimized Petroleum Coke IGCC Coproduction Plant

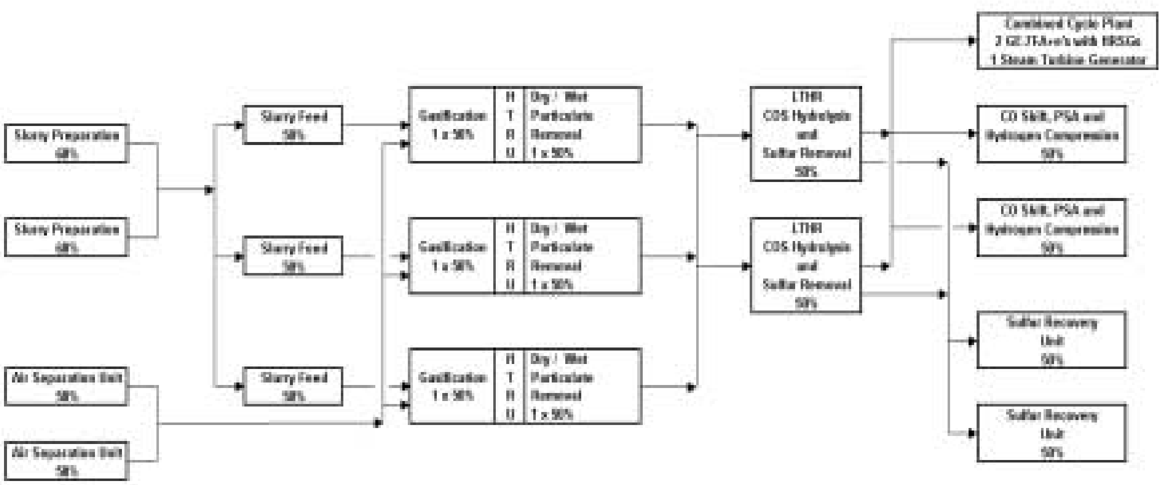


Notes: Capacity percentages are based on total plant capacity.

Figure 7

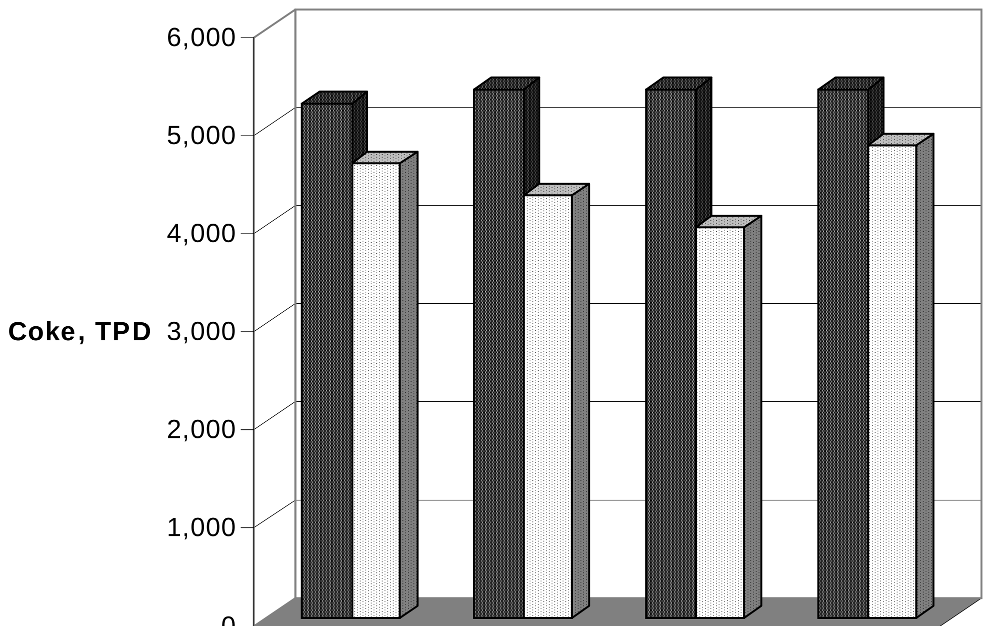
Subtask 1.3S Spare Gasification Train Case - Block Flow (Train) Diagram

Optimized Petroleum Coke IGCC Coproduction Plant



Notes: Capacity percentages are based on total plant capacity.

Figure 8
Design and Daily Average Coke Consumptions



	Subtask 1.2	1.3 Base Case	1.3 Min Cost	1.3 Spare Gasification Train
Design	5,249	5,399	5,399	5,399
Average	4,635	4,310	3,973	4,814

Figure 9
Equipment Availability

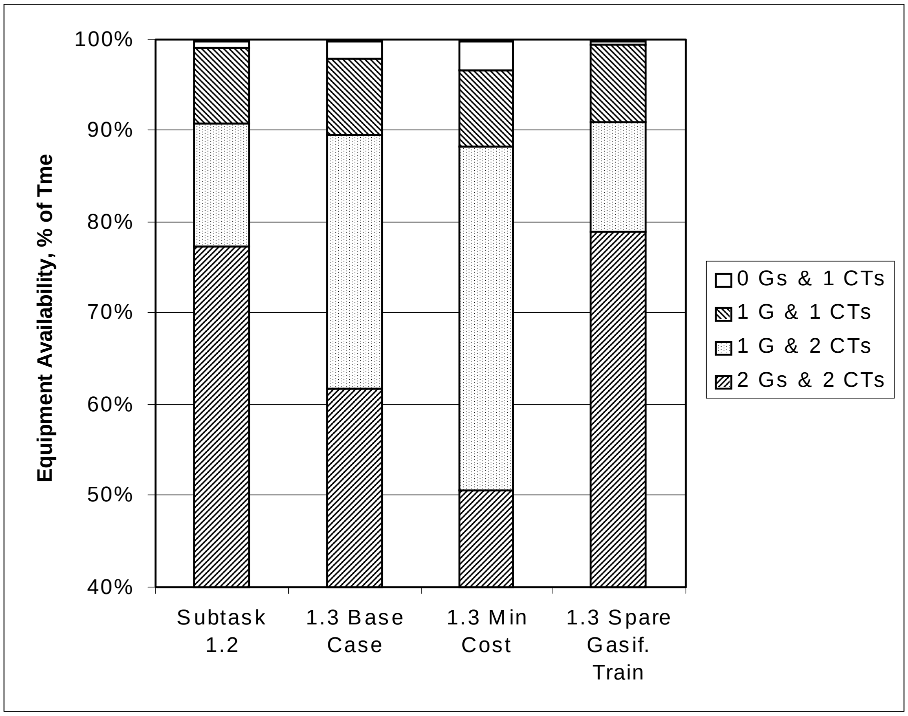


Figure 10
Equivalent Power Availability

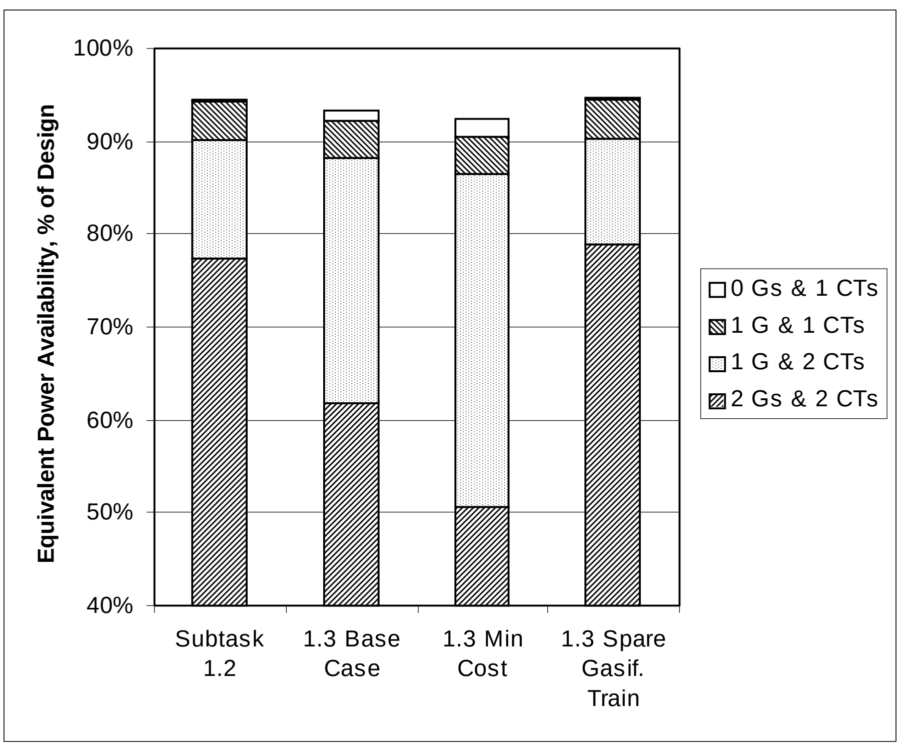


Figure 11
Effect of Power Selling Price on the Return on Investment

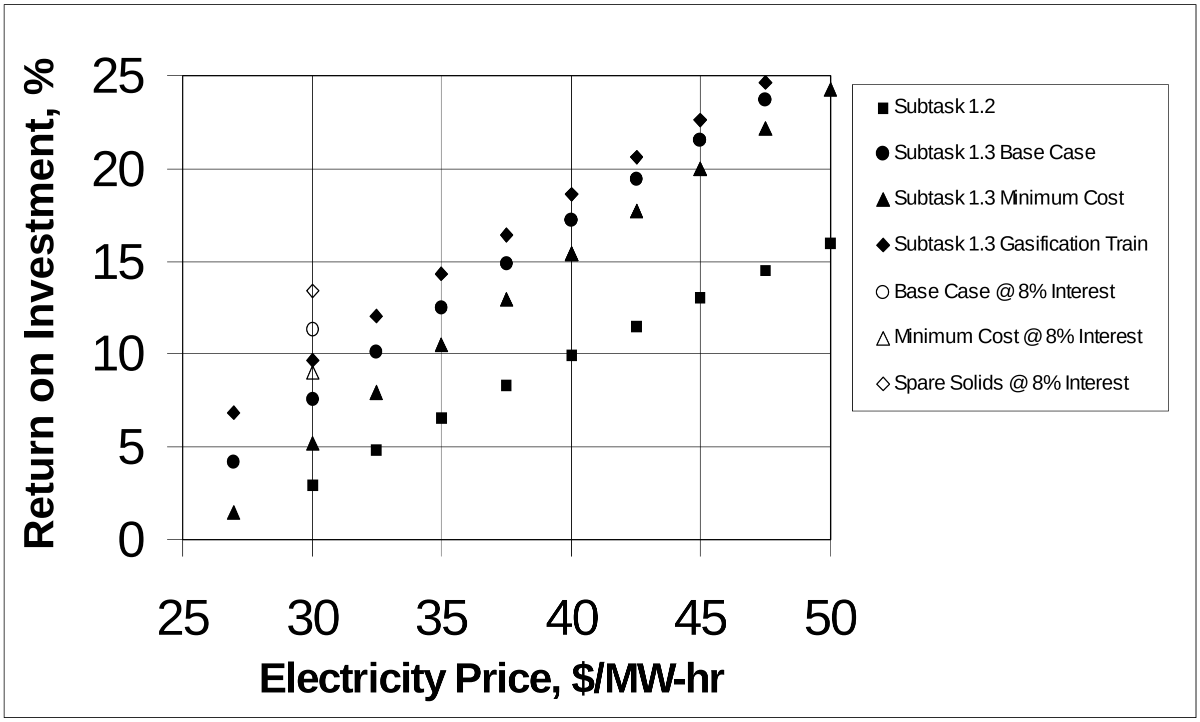


Figure 12
Effect of Natural Gas Price and Associated
Product Prices on the Return on Investment